Appendix D Location Specific Forecasting and Marginal T&D Cost Study

REPORT

Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods

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Prepared for
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1 Introduction

One vital role of the electric utility is to ensure that electricity supply remains reliable. By projecting future demand and reinforcing the local distribution network so that distribution capacity is available to meet local needs as they grow over time, costly outages are avoided.

A key focus of the New York Public Service Commission's REV proceeding is to defer or eliminate the need for traditional T&D infrastructure investments by using DERs. This requires quantifying the potential to avoid or defer infrastructure upgrades as granularly as possible.

The growth of DERs is fundamentally changing the nature of distribution system forecasting, planning, and operations. Forecasting location specific loads and DERs using probabilistic methods is becoming increasingly critical for T&D planning. However, local demand growth trajectories based on historical growth are inherently uncertain and those forecasts grow more uncertain further into the future. Location specific, granular forecasts are also essential to establishing the location specific value of DERs and identifying locations where DERs are beneficial. Simply put, location specific forecasting and planning methods have direct implications for DER integration.

To our knowledge, no other utility to date has attempted to implement a location specific avoided T&D cost study that relies on probabilistic analysis and quantifies the option value of reducing peak demand. We emphasize that the development of probabilistic load forecasts and avoided T&D costs at a granular, local level is a new endeavor and will require refinements and improvements with more applied experiance.

This study focuses on substation and transmission costs (it does not include circuit feeders) and was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level
- Develop location specific forecasts of growth with uncertainty
- Quantify the probability of any need for infrastructure upgrades at specific locations
- Calculate local avoided T&D costs by year and location using probabilistic methods
- Identify beneficial locations for DERs

There are several aspects of the study that make it unique. First, the T&D avoided costs estimates being produced are at a local level. Most studies of avoided T&D costs have been conducted in the context of energy efficiency and focused on producing system wide values, often concentrating on historical T&D expenditures rather than future infrastructure investments.

Second, the study uses a bottom-up approach to quantify historical year-to-year growth patterns and the amount of variability in growth.

Third, we develop load growth forecasts and avoided cost estimates using probabilistic methods rather than straight-line forecasts. The approach takes into account the reality that we have much greater uncertainty 10 years out than a year out, and accounts for the risk mitigation value of resources that manage local peak loads.

As a general rule, only growth-related T&D investments that are shared across multiple customers can be avoided by DERs or demand management. As loads grow, the excess distribution capacity that provides reliability dwindles. If a customer helps reduce coincident demand, either by injecting power within the distribution grid or by reducing demand, the unused capacity can accommodate another customer's load growth, thereby helping avoid or defer investments required to meet load growth. Avoided or deferred T&D investments free up capital for other alternate uses, improving the efficient use of resources.

Not all distribution investments are driven by local, coincident peak loads. Some investments are tied to customer interconnection costs and are essentially fixed. Other investments must take place because of aging or failed equipment or because of the need to improve reliability and modernize the grid. These investments typically cannot be avoided by managing loads with DERs.

The value of distribution deferral varies significantly across local distribution areas because of:

- Load growth rates and anticipated changes in load curve shapes, which affect whether infrastructure upgrades can be avoided and how long they can be deferred;
- The amount of existing excess capacity or the amount of additional load that can be supported without upgrades;
- The magnitude, timing, and cost of projected distribution upgrades; and
- The design of the distribution system.

In areas with excess distribution capacity—or areas where local, coincident peaks are declining or growing slowly—the value of distribution capacity relief can be minimal. In areas where a large, growth-related investment is imminent, the value of distribution capacity relief can be quite substantial, especially if it is possible to delay or defer distribution infrastructure upgrades for a substantial time. However, many Central Hudson distribution areas have declining or slowly growing loads, or they have sufficient capacity already built such that distribution investments are not needed in the foreseeable future.

The remainder of this report is organized in five sections.

- Section 2 provides an overview of the methodology.
- Section 3 presents the historical growth estimates.
- Section 4 details the avoided costs and the risk of triggering infrastructure upgrades or load transfers by location. We separately present the avoided T&D costs.
- Section 5 discusses how probabilistic forecasting and valuation is used to identify locations where DERs can be beneficial.
- Section 6 summarizes the key findings and conclusions.

2 Methodology

This section details the risk tolerance for different types of equipment, data sources used, and key steps in developing location specific forecasts and avoided T&D cost. Before doing so, we discuss why probabilistic methods are critical not only to forecasting, but also to quantifying location specific avoided T&D costs.

2.1 Risk Tolerance for T&D Components

When demand exceeds normal and emergency equipment ratings, equipment can become overloaded and degrade more quickly, considerably increasing the risk of an adverse reliability event, although overloads are uncommon. With the exception of rural substations, most of Central Hudson's system is designed to withstand the loss of the highest rated source (e.g., the loss of a transmission line, transformer, or other component) without violating thermal or voltage limits – that is, the substation or area design rating is often equal to the rating of the lowest equipment rating. As a result, loads in excess of the load serving capability, or design rating, do not automatically result in overloads or an infrastructure upgrade. However, Central Hudson also does not wait for loads to exceed the allowable risk to begin construction.

Central Hudson has specified explicit risk tolerances and detailed the total hours that forecasted load can exceed design ratings. The risk tolerance varies by component and more risk is tolerated for less critical components, as shown in Table 2-1. The risk tolerance levels are based on the total hours design ratings are exceeded.

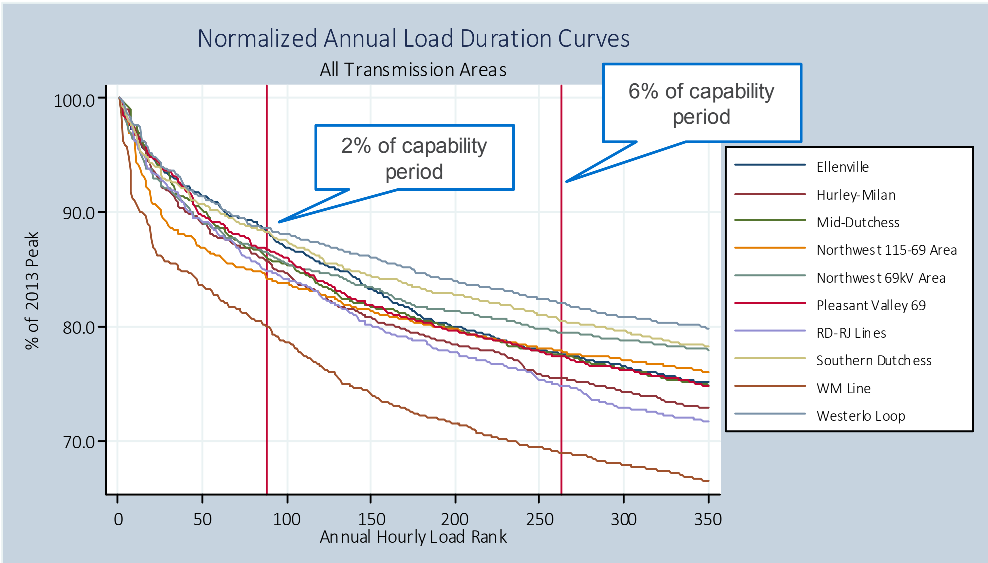
Table 2-1: Risk Tolerance Levels

Category	Risk Tolerance
Transmission Network	2% of seasonal capability period (88 hours)
Transmission Loop	6% of seasonal capability period (263 hours)
Urban Substation	6% of seasonal capability period (263 hours)
Rural Substation	8% of seasonal capability period (350 hours) or 7 MVA unreserved

Figure 2-1 illustrates the practical implications of the risk tolerance levels on the demand level that can be accommodated. The graphs reflect the 2013 load duration curves for Central Hudson's 10 transmission areas. All of the lines rank demand for each hour in the year from highest to lowest. The graph only shows the top 350 (<4% of hours) in the year. All of the load duration curves show hourly demand as a percent of each area's 2013 (1-in-2) peak, allowing side-by-side comparisons for areas with a different magnitude of demand.

Because of inherent variation in load duration curves, the amount by which loads can exceed the design ratings varies for individual transmission areas and substations. For transmission networks—Ellenville, Northwest 115-69 kV, Northwest 69 kV, and Pleasant Valley 69kV—this means loads can exceed design ratings by 13-16% without exceeding the allowable risk tolerance. For transmission loops, loads can exceed design ratings by 20-45%.

Figure 2-1: Normalized Load Duration Curves



2.2 Why Use Probabilistic Forecasting and Planning Methods?

No one knows in advance precisely when loads will exceed design ratings or by how much; however, linear forecasts assume precise knowledge. In practice, actual growth trajectories are rarely linear and growth patterns trend across time – both load growth and load declines follow cyclical patterns.

Figure 2-2 contrasts a linear forecast against two simulated potential growth trajectories, all using the same 1.5% growth rate. The linear forecast indicates loads will exceed the design rating in 10.5 years and the risk tolerance cutoff in exactly 21 years. But actual growth rarely follows a linear pattern. Loads could exceed the design and risk tolerance far earlier, as shown by Path 1, or never at all, as shown by Path 2. But the two potential outcomes are not equally probable.

Figure 2-2: Comparison of Linear Forecast and Potential Growth Patterns

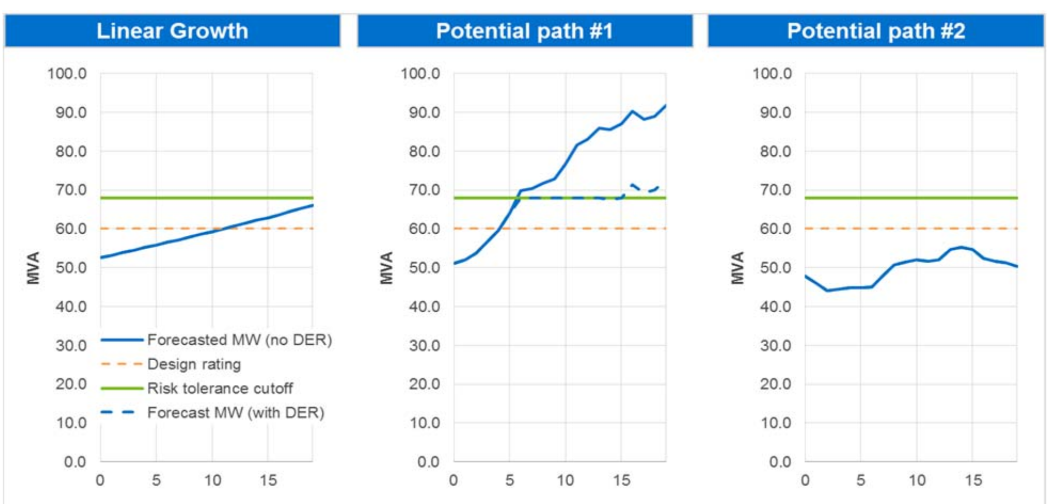
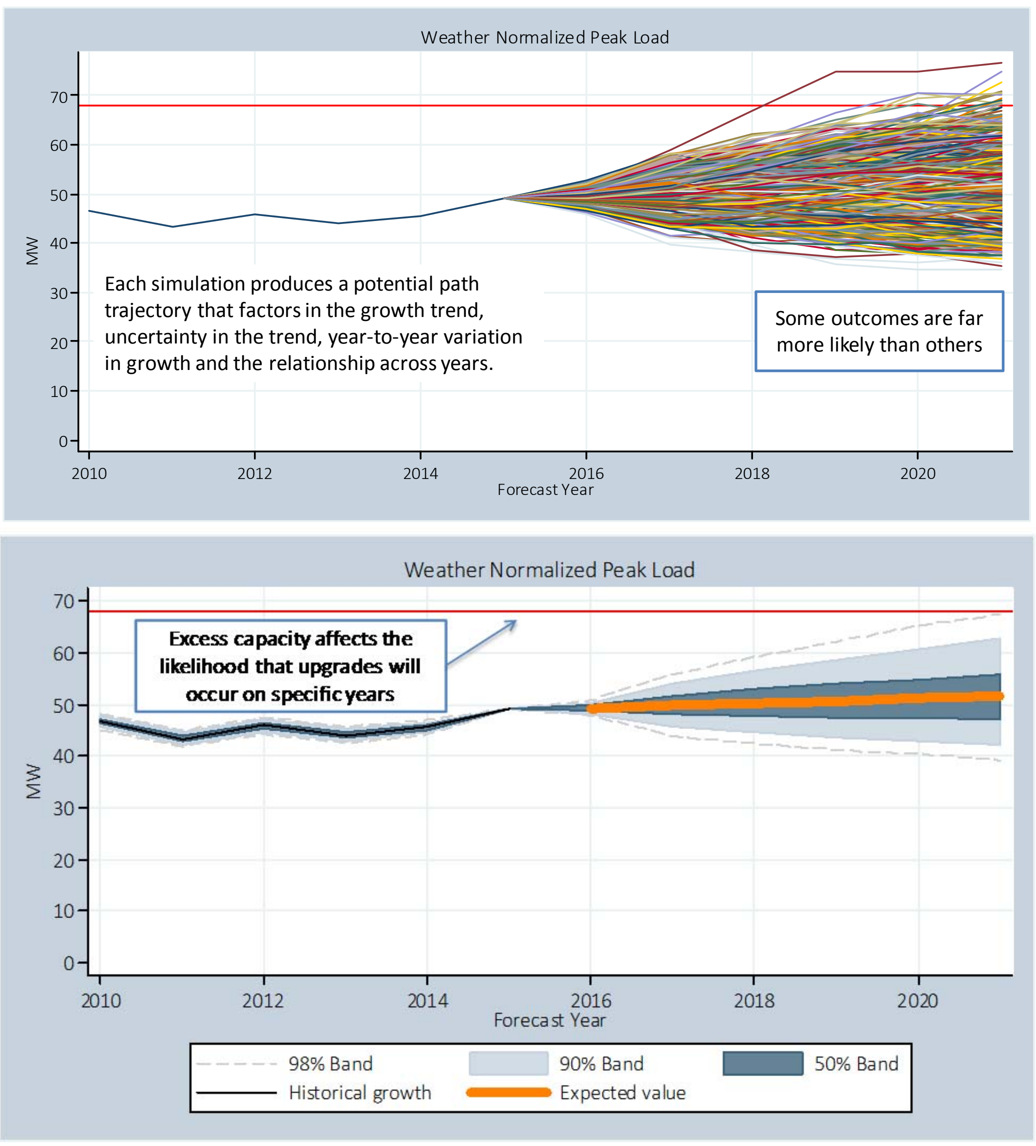


Figure 2-3 illustrates the critical role of probabilistic, location-specific forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories thousands of times, as shown in the top panel. Some outcomes are far more likely than others and are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands, as shown in the bottom panel.

Forecasts inherently include uncertainty and become more uncertain further into the future. Because a linear forecast assumes exact knowledge, no value is assigned to the years before the linear forecast exceeds the risk tolerance. Probabilistic methods, on the other hand, reflect the potential reality that infrastructure could be triggered earlier. Probabilistic methods will assign value to periods earlier than the linear forecast would dictate based on the probability of triggering an earlier infrastructure upgrade.

Figure 2-3: Illustration of Location Specific Simulations and Probabilistic Forecasts



2.3 Data Sources

The study relied on six main data sources:

1. 2010–2015 hourly interval data for most substations and each transmission area;
2. 2010–2015 weather data from the Dutchess County Airport;
3. 1-in-2 weather year peak conditions data;
4. 1-in-2 forecasted Central Hudson System loads;
5. Design rating information for each substation and transmission area; and
6. Costs for infrastructure upgrades.

With the exception of the 2010–2015 weather data, all of the above data was supplied by Central Hudson. A few points are noteworthy, however. First, the 2010–2015 time period was selected because of data availability and due to the significant shift in loads that occurred with the 2009 economic downturn.

Secondly, not all substations have hourly interval data, and the quality and availability of the data degrades when longer time spans are included.

Third, resources that have been procured as part of Central Hudson's NWA projects are incorporated by adjusting the design rating. The additional resources reduce loads, thereby leading to additional room for growth.

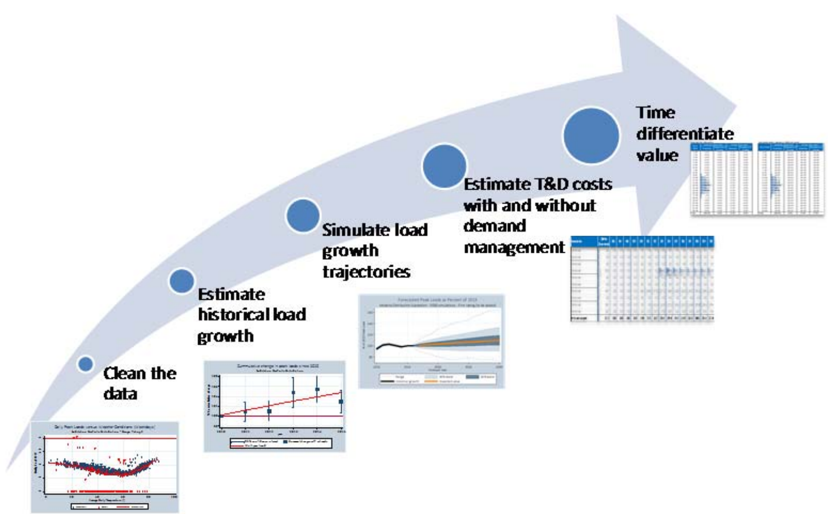
Finally, the quality of the data improves for larger aggregation points, such as transmission areas, where all of the historical data is available. Not all substations and feeders have hourly data and among those that do, not all of them have the same amount of historical data. To define the growth trends one needs several years of data.

Because multiple years of data are required, the forecasts and location specific estimates of T&D avoided costs were developed for locations with at least three years of valid hourly data. This includes 54 of Central Hudson's 62 distribution load serving substations. All of the transmission areas were included in the analysis.

2.4 Key Analysis Steps

describes the main steps in developing location specific avoided T&D costs using probabilistic methods. The process was implemented for each substation, load area, and transmission area with at least three years of valid, historical hourly data. Importantly, the 2,000 or 10,000 simulations of potential growth trajectories are critical to both the forecast and to estimating T&D costs with and without demand management.

Figure 2-4: Key Steps in Estimating Location Specific Avoided Costs

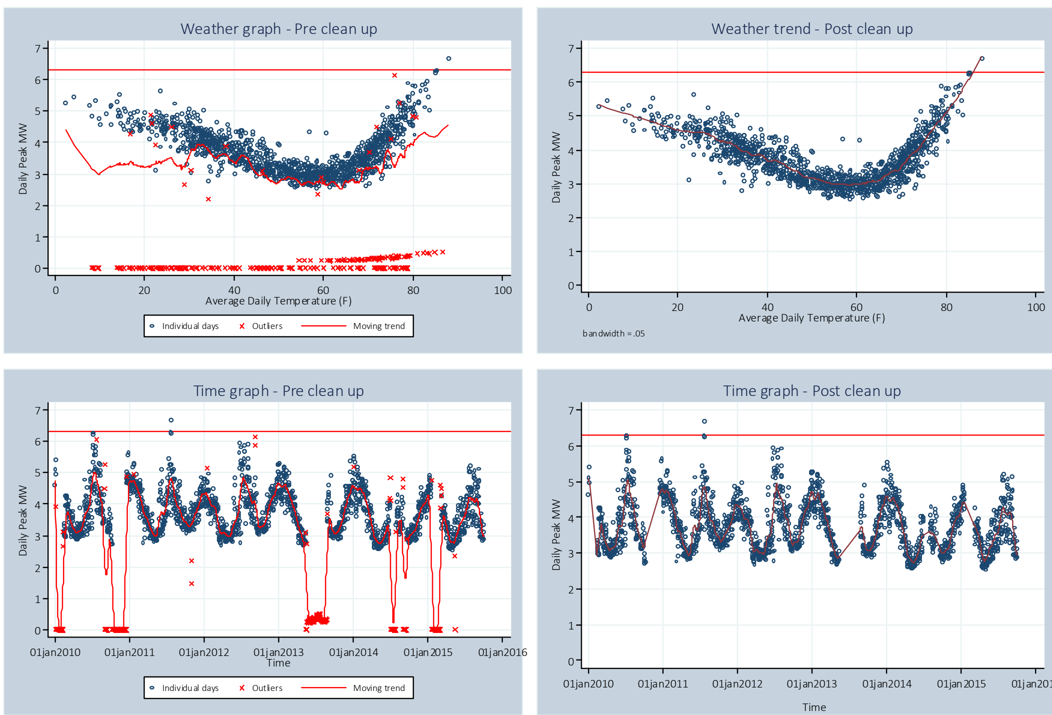


Clean the data

One of the key challenges in estimating load patterns and growth at granular locations is the quality of data. Not all substations have metered data over the relevant historical period and, for those that do, it is important to identify and remove load transfers, outages, data gaps, and data recording errors. Nexant used data analytics to identify loads with irregular patterns, load transfers, data gaps, and outages from substation level data. We subsequently reviewed those loads with Central Hudson's engineers to confirm dates where load transfers occurred.

Figure 2-5 below illustrates an example of a location with load transfers, which, unless detected, can be mistaken for a load increase and distort the sensitivity of the area's loads to weather.

Figure 2-5: Example of Data Cleaning

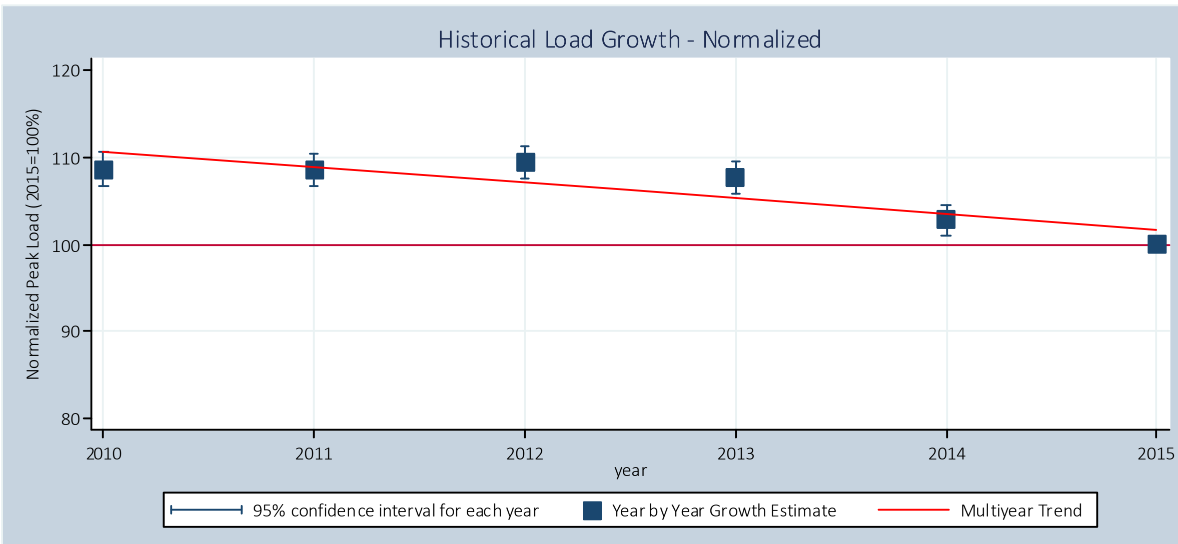


Estimate historical load growth.

The objective of this step was to estimate historical load growth for each year in 2010–2015 in percentage terms. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year—technically known as *auto-correlation*. The econometric models were purposefully designed to both estimate historical load growth and allow us to weather normalize loads for 1-in-2 weather peaking conditions. We normalized 2010–2015 peaks for 1-in-2 weather peak conditions because it is Central Hudson's criteria for distribution design. Appendix A describes the econometric models.

Figure 2-6 illustrates some of the key outcomes from this analysis. First, the analysis produces year-by-year estimates of the historical growth or decline in loads after controlling for differences in weather, day of week, and season. Second, the year-by-year estimates allow us to estimate the growth trend. In the below example, loads are declining at a rate of 1.8% per year. Third, the results enabled us to estimate of the variability in year-to-year growth patterns (also known as the standard error of the forecast).

Figure 2-6: Year-by-year Estimates of Historical Growth



Simulate potential load growth trajectories

The load growth forecasts were developed using probabilistic methods—*Monte Carlo* simulations—that produced the range of possible load growth outcomes by year. It simulates the reality that the near-term forecast has less uncertainty than forecasts 10 years out. A total of 2,000 simulations were implemented for each substation and load area, and 10,000 simulations were implemented for each transmission area. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

The simulations are based on historical growth patterns from the econometric models. Each forecast year's growth is a combination of an independent growth component and the prior year's growth trajectory.[1] The independent growth component is based on a random draw that factors in the historical trend, the uncertainty around the trend, and the year-to-year variation at the location. The forecasts are cumulative, meaning that each simulation's forecast trajectory builds on the prior year, producing a path. The process was repeated 2,000 times for each substation & load area and 10,000 times for each transmission area. The result is a full picture of the possible load growth outcomes by year. Each of the 2,000 (or 10,000) simulated growth trajectories produces specific information about if and when the design rating

[1] $Annual\ growth_t = Independent\ growth_t \cdot (1 - autocorrelation) + Annual\ growth_{t-1} \cdot autocorrelation$

would be exceeded and the amount of demand management required to maintain loads below the design ratings.

Estimate costs with and without demand management

The estimates of the avoided T&D costs are based on the load growth forecast and the outcome of each simulation run. The process involved applying the below four steps to each of 2,000 (or 10,000) simulation runs for each location:

1. Identify the timing of the infrastructure investments for each simulation run, location, and year. For each location, each simulation run produced a potential growth trajectory, which either exceeded the design rating or remained below it. As noted earlier, when loads exceed design ratings, they do not automatically trigger infrastructure upgrades. Loads can exceed design ratings without triggering overloads and Central Hudson has explicit risk tolerance levels where less risk is tolerated for more critical components. Because load growth doesn't follow a perfect linear trajectory, loads also can exceed the design ratings for a year or two, but revert to levels below the design rating. To reflect this complexity, the timing of infrastructure upgrades was simulated to occur the year after loads exceeded design ratings for two consecutive years.
2. Identify the magnitude of demand management needed to maintain loads below the design rating. Once demand management resources were needed, we assumed they were in place for 10 years.
3. Model T&D infrastructure costs with and without demand management for each simulation run, location, and year. When the design ratings were exceeded for two consecutive years, the costs of the infrastructure investments were included in the third year and allocated based on the book life of the upgrade. For example, equipment worth $15 million with a 50-year book life would be spread or annualized over 50 years, with a 20% carrying cost.

   The operations and maintenance costs were included using standard values for transmission, distribution substations, and feeders.[2] This replicated how the T&D costs would be reflected in the rate base. We also implemented the same calculations but instead assumed the investment could be deferred for up to 10 years or until 10% of the peak was managed through DERs, whichever came first. This process reflected the reality that most projects cannot be postponed indefinitely and the length of deferral may be shorter in areas with rapid growth.
4. Calculate the avoided costs per kW for each simulation run, location, and year. If loads were not projected to exceed the respective design rating, no costs are avoided since a growth related infrastructure investment would not have taken place anyhow. If the loads in a particular simulation exceeded the design rating, reducing loads to levels below the design rating would avoid or defer growth related infrastructure investment. Thus, the avoided costs are the difference between the costs with and without the reduction in loads necessary to avoid or defer the upgrade.

The detailed calculations for each of the 2,000 or 10,000 simulations at each site were subsequently used to estimate the expected avoided costs per kW at each location for each year.[3] Because the analysis relied on probabilistic

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[2] The annualized cost were calculated using the below standard formula, where *r* is the post-tax discount rate and *n* is asset book life:

$$Annualized\ Cost = Total\ cost \cdot \frac{r(1+r)^n}{(1+r)^{n-1}}$$

[3] The expected avoided costs is calculated across all simulation runs for each year (t) at an individual location (i) by using the ratio of the average avoided costs and average demand reductions required to attain them.

methods, the avoided cost estimates reflects the risk mitigation value of managing loads to remain below the design rating. That is, the probabilistic method assigns T&D avoided costs to location and year with, for example, a 10% likelihood of an upgrade. In contrast, a linear forecast would not assign any value to that year.

Figure 2-7 illustrates the process with and without demand management for a single simulation at one location, assuming a $5M infrastructure upgrade. This process is repeated thousands of times.

Figure 2-8 illustrates the probabilistic approach to avoided costs. In the example, 68% of the simulations do not lead to any infrastructure upgrades over the immediate 10 years. A straight line forecast would lead to an avoided cost estimate of zero (p50), yet due to the probability of exceeding design rating, DERs still provide value.

2.5 Integration of DERs

One of the most important considerations is accurately reflecting the locational value of incremental resources. This creates a paradox: including DERs which have not yet been built and installed into forecasts, lowers load forecasts and dilutes the locational value of DER resources. The forecasts reflect the trends in net loads and, arguably reflect naturally occurring DER and energy efficiency targets, which in the near term are similar to past goals. They do not include incremental DER resources which are not naturally occurring since the goal of the study is to quantify the avoided T&D infrastructure costs per unit of demand reduction.

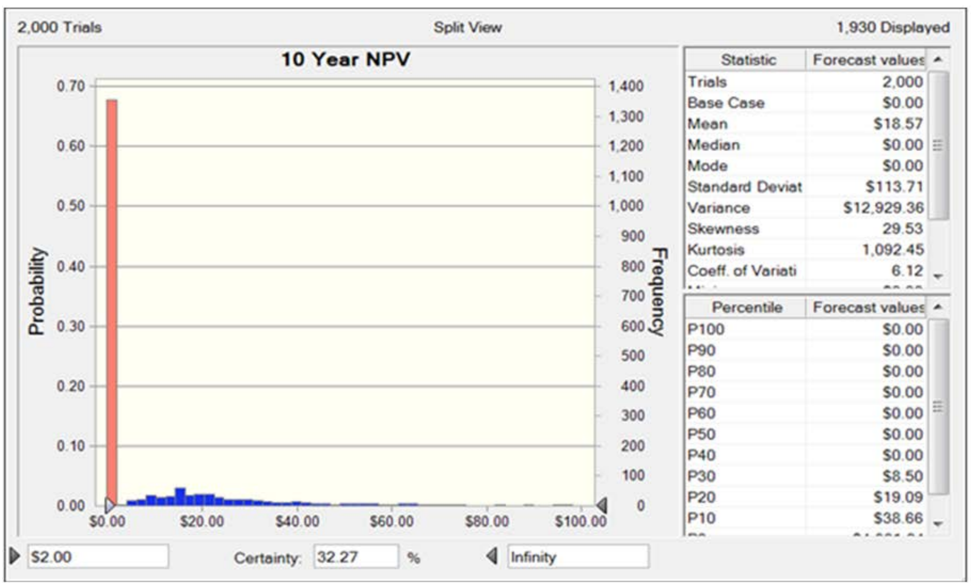
$$Expected\ Avoided\ Costs_{i,t} = \frac{\sum_{r=1}^{2,000} Avoided\ Cost_{i,t,r}}{\sum_{r=1}^{2,000} MW\ reduction\ required_{i,t,r}}$$

Figure 2-7: Example Calculation of T&D Costs with and without Demand Management

Calculations

								Costs without DER		Costs with DER			
Forecast year	Annual growth	Cummulative growth multiplier	Forecasted MW (no DER)	Risk tolerance cutoff	MW over	DER resources needed	Forecast MW (with DER)	Annualized capital cost	O&M	Annualized Upgrade Cost (w DER)	O&M	**Avoided cost**	**$/kW**
0	5.3%	105.3%	54.8	65	0.0	0.0	54.8	$0	$0	$0	$0	$0	$0.00
1	4.8%	110.9%	57.6	65	0.0	0.0	57.6	$0	$0	$0	$0	$0	$0.00
2	4.5%	116.2%	60.4	65	0.0	0.0	60.4	$0	$0	$0	$0	$0	$0.00
3	1.2%	121.5%	63.2	65	0.0	0.0	63.2	$0	$0	$0	$0	$0	$0.00
4	1.9%	123.0%	64.0	65	0.0	0.0	64.0	$0	$0	$0	$0	$0	$0.00
5	1.6%	125.3%	65.2	65	0.2	0.2	65.0	$636,624	$176,584	$0	$0	$813,208	$4,857.66
6	-0.6%	127.4%	66.2	65	1.2	1.2	65.0	$636,624	$180,292	$0	$0	$816,917	$664.08
7	-2.0%	126.6%	65.8	65	0.8	1.2	64.6	$636,624	$184,079	$0	$0	$820,703	$667.16
8	-0.8%	124.1%	64.5	65	0.0	1.2	63.3	$636,624	$187,944	$0	$0	$824,568	$670.30
9	4.3%	123.0%	64.0	65	0.0	1.2	62.8	$636,624	$191,891	$0	$0	$828,515	$673.51
10	2.6%	128.4%	66.7	65	1.7	1.7	65.0	$636,624	$195,921	$0	$0	$832,545	$477.71
11	1.8%	131.7%	68.5	65	3.5	3.5	65.0	$636,624	$200,035	$0	$0	$836,659	$241.26
12	2.5%	134.0%	69.7	65	4.7	4.7	65.0	$636,624	$204,236	$0	$0	$840,860	$178.85
13	2.7%	137.4%	71.4	65	6.4	6.4	65.0	$636,624	$208,525	$0	$0	$845,149	$131.31
14	4.2%	141.1%	73.4	65	8.4	8.4	65.0	$636,624	$212,904	$0	$0	$849,528	$101.41
15	3.0%	147.0%	76.4	65	11.4	8.4	68.1	$636,624	$217,375	$783,683	$267,588	-$197,272	-$23.55
16	4.0%	151.4%	78.7	65	13.7	8.4	70.4	$636,624	$221,940	$783,683	$273,207	-$198,327	-$23.67
17	1.8%	157.4%	81.9	65	16.9	8.4	73.5	$636,624	$226,600	$783,683	$278,945	-$199,403	-$23.80
18	1.4%	160.2%	83.3	65	18.3	8.4	74.9	$636,624	$231,359	$783,683	$284,803	-$200,503	-$23.93
19	2.2%	162.4%	84.4	65	19.4	8.4	76.0	$636,624	$236,218	$783,683	$290,783	-$201,625	-$24.07

Figure 2-8: Example of Probabilistic Avoided Cost Estimates



Year	Risk of triggering upgrade (no DER)
0	0%
1	0%
2	0%
3	1%
4	4%
5	7%
6	12%
7	17%
8	23%
9	28%
10	32%

3 Historical Load Growth Trends

This section presents the data on historical peak loads, design ratings, and load growth estimates. The results are presented separately for transmission and distribution areas. A key distinction between probabilistic and straight line forecasts is that the former approach explicitly accounts for the reality that forecasts are more uncertain further into the future.

Growth can slow down or accelerate in comparison to recent growth patterns and, in practice, actual growth trajectories rarely are linear. When a location has more room for growth, the chances it will exceed the design rating and trigger the need for infrastructure upgrades is lower. The results presented in this section focus on the growth rates, loading factors, and the standard error of the forecast.[4]

3.1 Transmission Load Growth Estimates

Locations with potential T&D infrastructure deferral value are areas where loads are growing but there is limited room to accommodate growth. Areas with sufficient load serving capability and areas where local, coincident peaks are declining are less likely to trigger growth related infrastructure upgrades.

Figure 3-1 compares the annual load growth rate to the loading factor (peak / design rating) for each of Central Hudson's ten transmission areas. The majority of Central Hudson's transmission areas are experiencing slowing or declining loads or have ample room for growth without having to upgrade the transmission system. However, upgrades may be required due to aging equipment or grid modernization efforts.

Locations with a growth factor above 0% are experiencing growth and locations where the 2015 loading factor is closer to 100% have less room for growth. All other things equal, a location with a 2.0% annual growth rate will exceed ratings in half the time as a location with a 1% growth rate. The chart, however, does not factor in the uncertainty of future growth patterns.

Figure 3-1: Transmission Area Growth Rates Versus Room for Growth

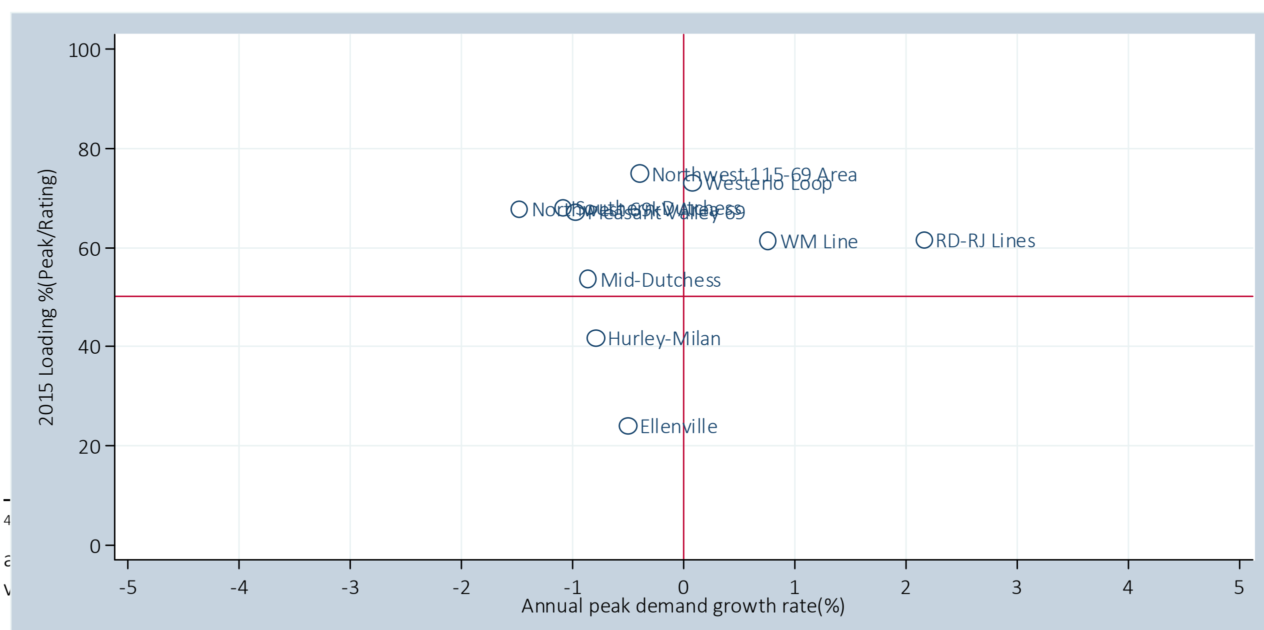


Table 3-1 summarizes the historical year by year growth for each transmission area, the growth trend, and the variability in the growth patterns, also known as the standard error of the forecast. The year-by-year growth estimates are indexed so 2015 equals 100%. They were estimated using econometric models designed to disentangle year by year growth rates from differences in weather patterns, day of week effects, and seasonality. For the most part, the year by year estimates of growth are relatively precise. The confidence bands around those estimates and the explanatory power of the models are summarized in Appendix A. Historical year by year growth does not follow a linear pattern and varies around the general trend line. This variation was used to develop the standard error of the forecast, which reflect how year to year growth can vary. This variability or uncertainty in the growth pattern is critical to probabilistic forecasting. Because growth and declining loads compound over time, growth patterns can deviate substantially from the straight line forecast. An area where loads are projected to remain flat can exceed the load serving capability five to ten years out due to the uncertainty in the forecast, though the likelihood of doing so is lower than for an area that is growing.

Table 3-1: Transmission Area Historical Load Growth Estimates (2010-2015)

Transmission area	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Historical annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Ellenville	60.7	251	101.6%	100.2%	95.3%	97.3%	96.7%	100.0%	-0.5%	2.5%
Hurley-Milan	80.7	193	104.2%	102.9%	103.3%	101.3%	101.2%	100.0%	-0.8%	0.5%
Mid-Dutchess	121.6	226	103.2%	103.1%	106.0%	103.4%	99.0%	100.0%	-0.9%	2.1%
Northwest 115-69 Area	116.3	155	-	102.1%	101.1%	101.2%	101.4%	100.0%	-0.4%	0.5%
Northwest 69kV Area	95.0	140	110.5%	101.8%	100.3%	101.1%	101.6%	100.0%	-1.5%	3.1%
Pleasant Valley 69	67.2	100	106.7%	106.0%	104.8%	111.3%	103.6%	100.0%	-1.0%	3.6%
RD-RJ Lines	88.7	144	85.7%	99.7%	99.9%	99.7%	99.5%	100.0%	2.2%	4.9%
Southern Dutchess	143.8	211	106.1%	103.6%	105.0%	103.5%	101.3%	100.0%	-1.1%	1.0%
WM Line	41.8	68	96.1%	88.4%	94.0%	90.3%	92.5%	100.0%	0.8%	4.3%
Westerlo Loop	66.4	91	101.4%	99.2%	99.9%	101.9%	101.6%	100.0%	0.1%	1.2%

Figure 3-2 summarizes the likelihood that loads will exceed design ratings for each transmission area by year. However, loads can exceed design rating without automatically triggering an infrastructure upgrade. Sustained growth needs to be observed before transmission lines are upgraded. Figure 3-3 summarizes the likelihood of triggering an infrastructure upgrade due to load growth. Based on the trajectory and variability in load growth, with the exception of the RD-RJ lines, the likelihood that loads will trigger an infrastructure upgrade over the next 10 years is less than 5% for all areas.

Figure 3-2: Probability of Load Exceeding Design Ratings

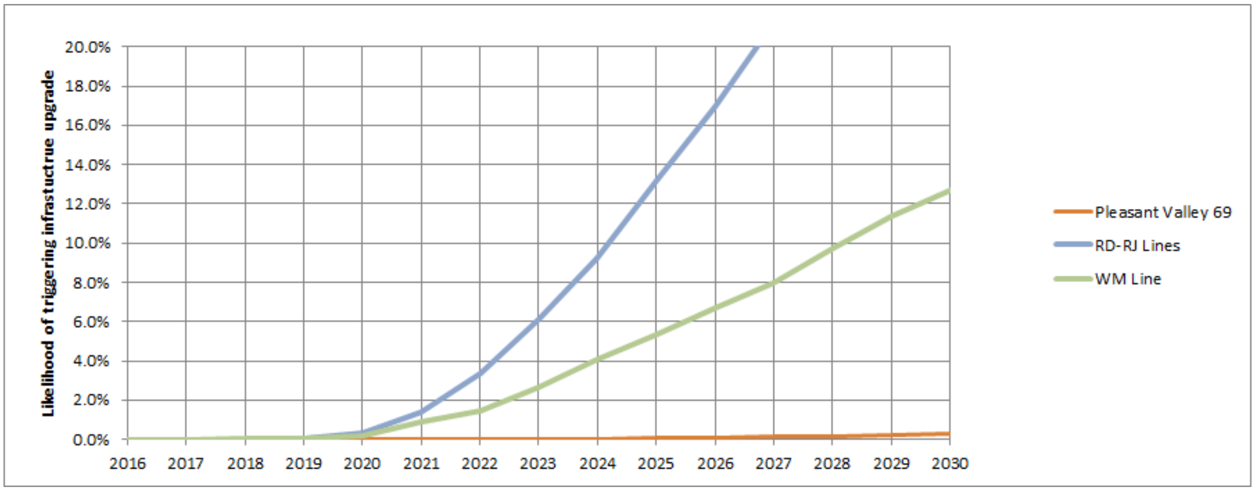
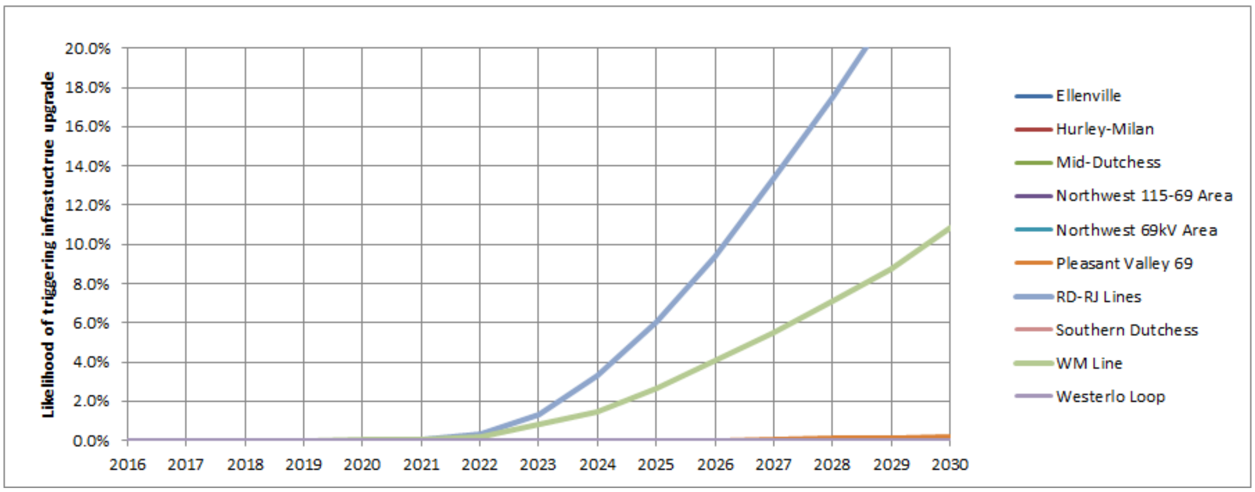


Figure 3-3: Probability of Growth Related Infrastructure Upgrade



3.2 Distribution Load Growth Estimates

Figure 3-4 compares the annual load growth rate to the loading factor (peak / design rating) for each of Central Hudson's substations with at least 3 years of hourly data. The majority of substations are experiencing slowing or declining loads or have ample room for growth without having to upgrade them. Locations with a growth rate above 0% are experiencing growth and locations where the 2015 loading factor is closer to 100% have less room for growth. Some substations, such as Lawrenceville and Grimley, are experiencing high growth levels but the growth trajectory is more uncertain because those substations have less historical hourly data than other sites. The only substation with limited room for growth is Woodstock. However, because of the distribution configuration, loads at Woodstock can be easily transferred to neighboring substations.

Figure 3-4: Substation Growth Rates Versus Room for Growth

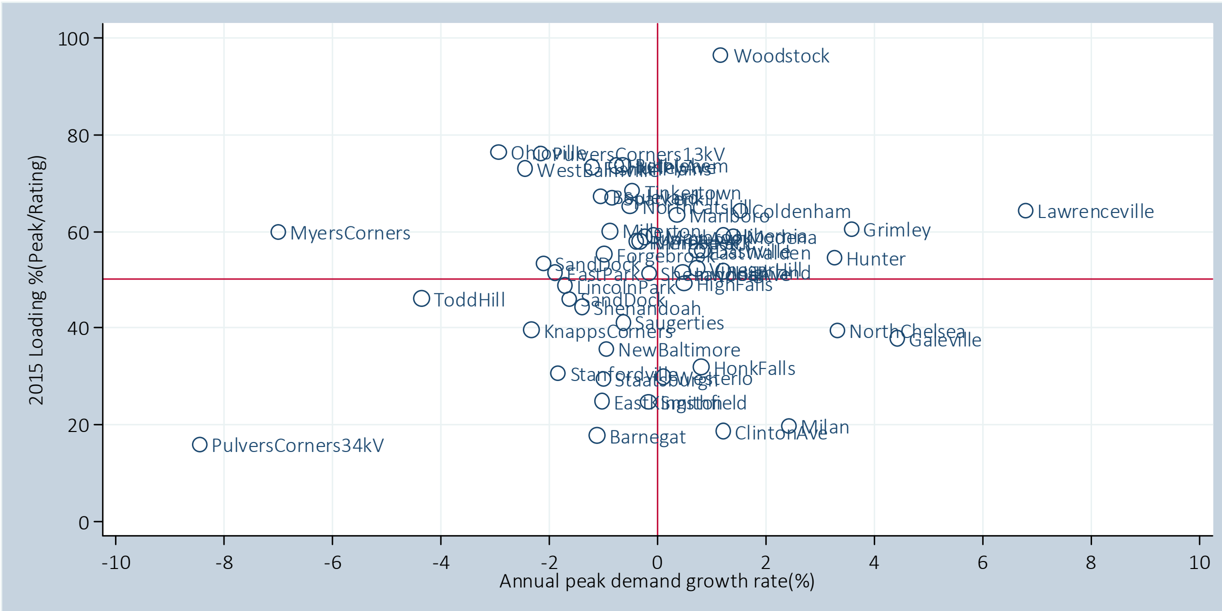


Figure 3-5 summarizes the likelihood that loads will exceed design ratings for each substation by year. However, loads can exceed design rating without automatically triggering an infrastructure upgrade. Sustained growth needs to be observed before substations are upgraded. Figure 3-6 summarizes the likelihood of triggering an infrastructure upgrade due to load growth. Based on the trajectory and variability in load growth, four substations – Coldenham, Grimley, Lawrenceville, and Woodstock – exhibit more than a 5% probability of triggering a growth related upgrade over the next 10 years. In some cases, upgrades can be deferred for longer periods through relatively low costs distribution upgrades or load transfers. DERs are still beneficial at those locations and their costs can be compared to the distribution upgrade and load transfer options.

Figure 3-5: Probability of Loads Exceeding Design Ratings

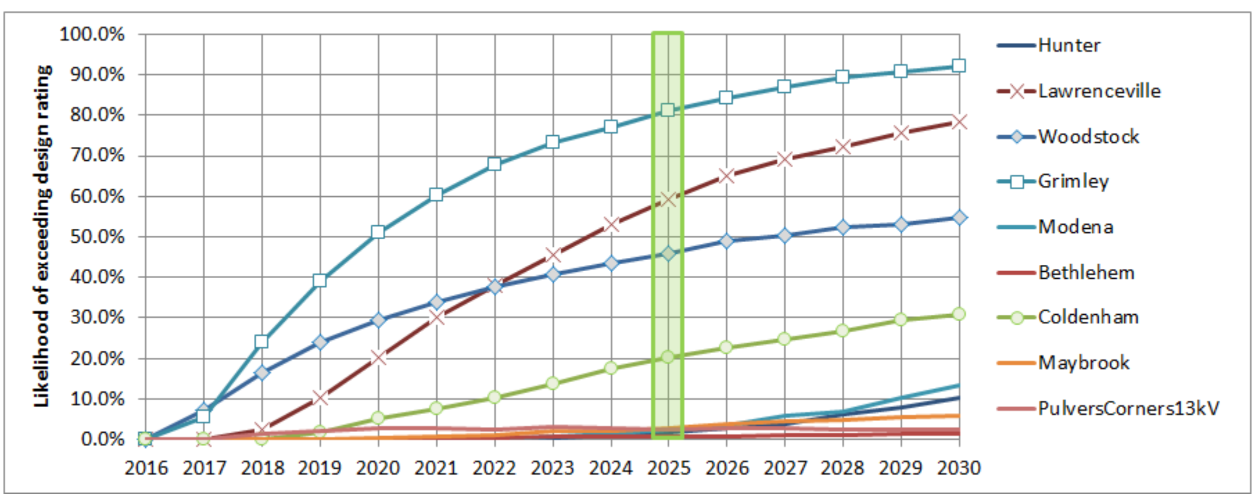
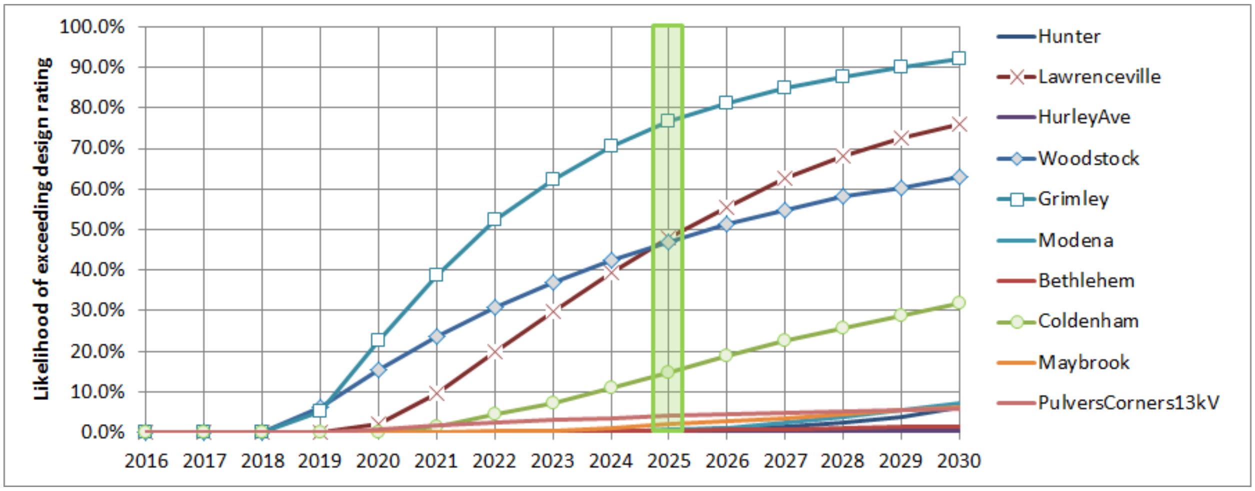


Figure 3-6: Probability of Growth Related Infrastructure Upgrade



Central Hudson groups substations in 10 distinct planning load areas. They represent adjacent geographic regions, but, more importantly, nearly all load transfers between substations occur within planning load areas. While the load growth estimates for specific substations can be influenced by load transfers and outages, the load areas provide a more stable unit of analysis.

Tables 3-2-through 3-10 summarize the results of the historical load growth analysis for each of the distribution load serving substations with at least three years of hourly data in each load area. Similar to the transmission areas, most of the substations have ample room to accommodate additional load growth.

Table 3-2: Northwest Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Hunter	10.7	19.5	84.1%	99.7%	102.1%	113.6%	106.0%	100.0%	3.3%	8.7%
Lawrenceville	12.4	19.3	-	-	-	83.3%	104.3%	100.0%	6.8%	10.3%
New Baltimore	9.2	25.8	105.9%	99.9%	98.6%	99.8%	99.0%	100.0%	-1.0%	2.4%
North Catskill	22.8	35.1	103.4%	100.6%	100.3%	101.5%	99.9%	100.0%	-0.5%	1.0%
Vinegar Hill	9.8	18.8	98.4%	95.1%	95.7%	99.7%	99.5%	100.0%	0.7%	1.9%
Westerlo	8.1	27.0	102.3%	99.5%	99.4%	103.0%	103.2%	100.0%	0.1%	2.0%
Overall load area	**66.2**	**0.0**	**88.8%**	**91.6%**	**91.1%**	**97.1%**	**102.9%**	**100.0%**	**2.7%**	**2.5%**

The Hunter and Lawrenceville substations both show relatively high growth forecasts; however, both are winter peaking—rather than summer peaking—and therefore are not managed by Dynamic Load Management programs designed for the summer. The growth in these regions was driven by the addition of large customers and seasonal activity and may or may not reflect future growth patterns.

Most of the substations in the Kingston-Saugerties load area are experiencing load declines rather than growth. With few exceptions, most of the substations have ample capacity to accommodate additional load growth. While the Boulevard and Hurley substations have experienced relatively high loadings in the past—87% and 89%, respectively—loads in these substations have been declining and the likelihood of an infrastructure upgrade is minimal. Woodstock had a historical high loading factor and the substation's loads have been growing. However, because of the distribution configuration, the additional loads can be easily transferred to neighboring substations at minimal cost.

The Ellenville load area substation loads are generally growing. However, they also have ample capacity to accommodate additional growth over the next 10 years.

Table 3-3: Kingston-Saugerties Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Boulevard	20.6	30.6	106.8%	104.0%	104.6%	106.1%	102.2%	100.0%	-1.1%	1.7%
East Kingston	12.0	48.0	105.8%	103.2%	105.3%	102.1%	101.9%	100.0%	-1.0%	1.2%
Hurley Ave	17.0	23.1	106.8%	100.9%	100.5%	103.4%	102.2%	100.0%	-0.8%	2.3%
Lincoln Park	41.0	84.0	108.1%	107.2%	105.1%	102.8%	101.6%	100.0%	-1.7%	0.4%
Saugerties	20.6	50.0	-	-	-	101.2%	101.3%	100.0%	-0.6%	0.6%
Woodstock	20.2	20.9	100.2%	85.9%	98.3%	101.2%	101.8%	100.0%	1.2%	6.0%
Overall load area	**105.0**	**0.0**	**106.1%**	**102.0%**	**103.1%**	**101.1%**	**102.0%**	**100.0%**	**-0.9%**	**1.3%**

Table 3-4: Ellenville Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Clinton Ave	1.4	7.7	96.7%	96.5%	95.6%	103.4%	103.1%	100.0%	1.2%	2.8%
Dashville	1.1	2.0	97.1%	99.6%	100.8%	102.1%	103.9%	100.0%	0.8%	1.9%
Grimley	4.4	7.2	-	-	80.4%	94.9%	99.0%	100.0%	3.6%	4.9%
High Falls	17.0	34.5	98.9%	97.4%	97.9%	100.8%	100.2%	100.0%	0.5%	1.2%
Honk Falls	5.8	18.2	98.3%	92.9%	98.0%	98.3%	100.8%	100.0%	0.8%	2.4%
Overall load area	**24.5**	**0.0**	**97.7%**	**94.6%**	**97.9%**	**100.3%**	**101.5%**	**100.0%**	**1.0%**	**1.8%**

Table 3-5: Modena Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Galeville	10.9	28.7	71.5%	80.1%	84.2%	86.1%	88.1%	100.0%	4.4%	3.0%
Highland	17.0	32.9	95.4%	94.9%	96.4%	99.3%	100.4%	100.0%	1.2%	1.0%
Modena	12.4	21.1	90.7%	98.2%	101.4%	99.9%	99.3%	100.0%	1.4%	3.2%
Ohioville	22.7	29.7	120.0%	110.5%	106.9%	108.3%	108.4%	100.0%	-2.9%	3.6%
Overall load area	**61.4**	**0.0**	**92.2%**	**98.2%**	**99.3%**	**100.2%**	**101.1%**	**100.0%**	**1.4%**	**2.2%**

The substations in the Modena distribution load area are experiencing growth but generally have ample capacity to accommodate additional growth without triggering infrastructure. The single exception is Ohioville, where loads have exceeded the current design rating in the past.. Ohioville was one of the initial locations included in Central Hudson's non-wire alternative demonstration projects. However, the DER resource bids were unable to cost-effectively address the need within the required timeframe.

Four of the substations in the Newburgh distribution load area are experiencing moderate growth but the remaining three substations are experiencing declining loads. There are three substations that have experienced high loading factors of 96.7%, 94.3%, and 90.2% in the 2010-2015 timeframe—Bethlehem Road, Maybrook, and West Balmville, respectively. However, loads at Bethlehem and West Balmville exhibit a downward trend and, as a result, loads are not forecast to exceed the design ratings. Maybrook loads are growing, albeit slowly. The low growth rate seen in Maybrook's historical data may be due, in part, to the recent history of transferring portions of the Maybrook areas to adjacent substations to accommodate new large loads that are fed from Maybrook. These circuit transfers will need to be reversed in the near future for reliability purposes.

With a few exceptions, the Northeastern Dutchess distribution load area substations have been experiencing declining loads. The two substations that have been experiencing growth—Hibernia and Milan—have ample capacity to accommodate additional load growth over the foreseeable future.

Table 3-6: Newburgh Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Bethlehem	35.2	47.8	104.4%	102.8%	95.3%	97.6%	102.2%	100.0%	-0.6%	3.6%
Coldenham	30.7	47.8	98.2%	97.7%	107.2%	114.0%	108.4%	100.0%	1.5%	6.8%
East Walden	14.6	26.2	99.3%	93.5%	97.4%	98.2%	100.3%	100.0%	0.7%	2.4%
Marlboro	19.6	30.9	96.6%	95.6%	99.4%	97.7%	94.3%	100.0%	0.4%	2.3%
Maybrook	17.7	30.0	93.3%	88.0%	84.6%	79.4%	83.4%	100.0%	-0.1%	8.3%
UnionAve	55.6	94.5	-	98.9%	102.8%	100.5%	98.2%	100.0%	-0.2%	2.0%
West Balmville	34.9	47.8	113.3%	112.3%	102.5%	104.1%	106.7%	100.0%	-2.4%	3.5%
Overall load area	**203.9**	**0.0**	**95.0%**	**96.6%**	**94.1%**	**99.8%**	**97.3%**	**100.0%**	**0.9%**	**1.8%**

Table 3-7: Northeastern Dutchess Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
East Park	12.4	24.2	106.0%	110.4%	105.1%	102.2%	99.4%	100.0%	-1.9%	2.5%
Hibernia	10.5	17.8	94.3%	99.1%	99.2%	102.1%	102.5%	100.0%	1.2%	2.2%
Milan	5.1	25.9	87.8%	88.3%	87.0%	90.8%	95.6%	100.0%	2.4%	2.6%
Millerton	5.0	8.3	106.3%	100.7%	100.9%	99.7%	100.9%	100.0%	-0.9%	1.9%
Pulvers Corners 13kV	4.4	5.8	109.5%	99.0%	101.1%	93.7%	91.3%	100.0%	-2.2%	5.4%
Pulvers Corners 34kV	2.7	17.2	137.7%	137.6%	138.7%	136.0%	103.4%	100.0%	-8.4%	11.0%
Rhinebeck	27.7	47.8	102.7%	100.7%	101.9%	101.5%	100.8%	100.0%	-0.4%	0.7%
Smithfield	1.4	5.8	100.8%	101.3%	102.0%	95.6%	103.7%	100.0%	-0.2%	3.0%
Staatsburgh	8.0	27.2	106.8%	102.7%	103.9%	105.7%	101.6%	100.0%	-1.0%	1.9%
Stanfordville	5.2	17.0	108.6%	108.5%	109.4%	107.6%	102.8%	100.0%	-1.8%	2.2%
Tinkertown	13.0	19.1	105.3%	98.9%	101.6%	102.1%	102.1%	100.0%	-0.5%	2.2%
Overall load area	**92.8**	**0.0**	**105.8%**	**104.1%**	**104.5%**	**100.7%**	**98.8%**	**100.0%**	**-1.4%**	**1.3%**

Based on the historical analysis, loads in the Poughkeepsie distribution load area have been trending downward. Moreover, the existing substations can accommodate substantial growth, should it occur, without growth related infrastructure upgrades.

Most of the substations in the Fishkill load area have been experiencing declining loads. The sole substation experiencing load growth, North Chelsea, has enough capacity in place to accommodate growth over the foreseeable future. One substation, Myers Corners, experienced a substantial drop in loads over the 2010-2015 period due in part to the closure of a large industrial facility.

The Poughkeepsie industrial substations have been experiencing moderate declines in peak loads and, more importantly, have ample capacity to accommodate load growth, should it occur. One of the load areas with a single substation is excluded because it exclusively serves a single large customer.

Table 3-8: Poughkeepsie Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Inwood Ave	24.6	47.8	94.3%	109.1%	94.7%	97.9%	103.0%	100.0%	0.5%	6.2%
Reynolds Hill[1]	34.7	45.9	113.8%	108.3%	106.6%	105.4%	100.0%	-	-2.7%	0.0%
Spackenkill	32.0	47.8	-	-	102.5%	101.4%	100.4%	100.0%	-0.8%	0.3%
Todd Hill	22.0	47.8	119.2%	118.3%	103.7%	101.3%	101.0%	100.0%	-4.4%	4.5%
Overall load area	**78.0**	**0.0**	**110.8%**	**124.7%**	**135.2%**	**132.8%**	**102.4%**	**100.0%**	**-3.0%**	**15.5%**

Table 3-9: Fishkill Distribution Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Fishkill Plains	38.7	52.8	105.2%	104.5%	106.4%	103.1%	100.0%	100.0%	-1.2%	1.6%
Forgebrook	26.2	47.4	106.7%	101.5%	104.0%	102.5%	101.5%	100.0%	-1.0%	1.6%
Knapps Corners	18.9	47.8	-	-	106.9%	102.1%	98.5%	100.0%	-2.3%	2.3%
Merritt Park	30.3	52.2	100.1%	102.4%	98.7%	98.1%	99.1%	100.0%	-0.3%	1.5%
Myers Corners	21.0	35.1	132.2%	126.9%	127.5%	121.0%	100.1%	100.0%	-7.0%	6.1%
North Chelsea	19.1	48.3	78.8%	95.9%	99.0%	99.7%	98.5%	100.0%	3.3%	6.1%
Sand Dock	4.3	8.0	108.3%	102.5%	111.6%	101.7%	100.5%	100.0%	-2.1%	4.0%
Shenandoah	9.2	18.0	106.3%	99.2%	104.7%	110.8%	106.3%	100.0%	-0.2%	4.9%
Overall load area	**179.0**	**0.0**	**113.6%**	**107.7%**	**102.9%**	**98.9%**	**92.9%**	**100.0%**	**-3.4%**	**4.1%**

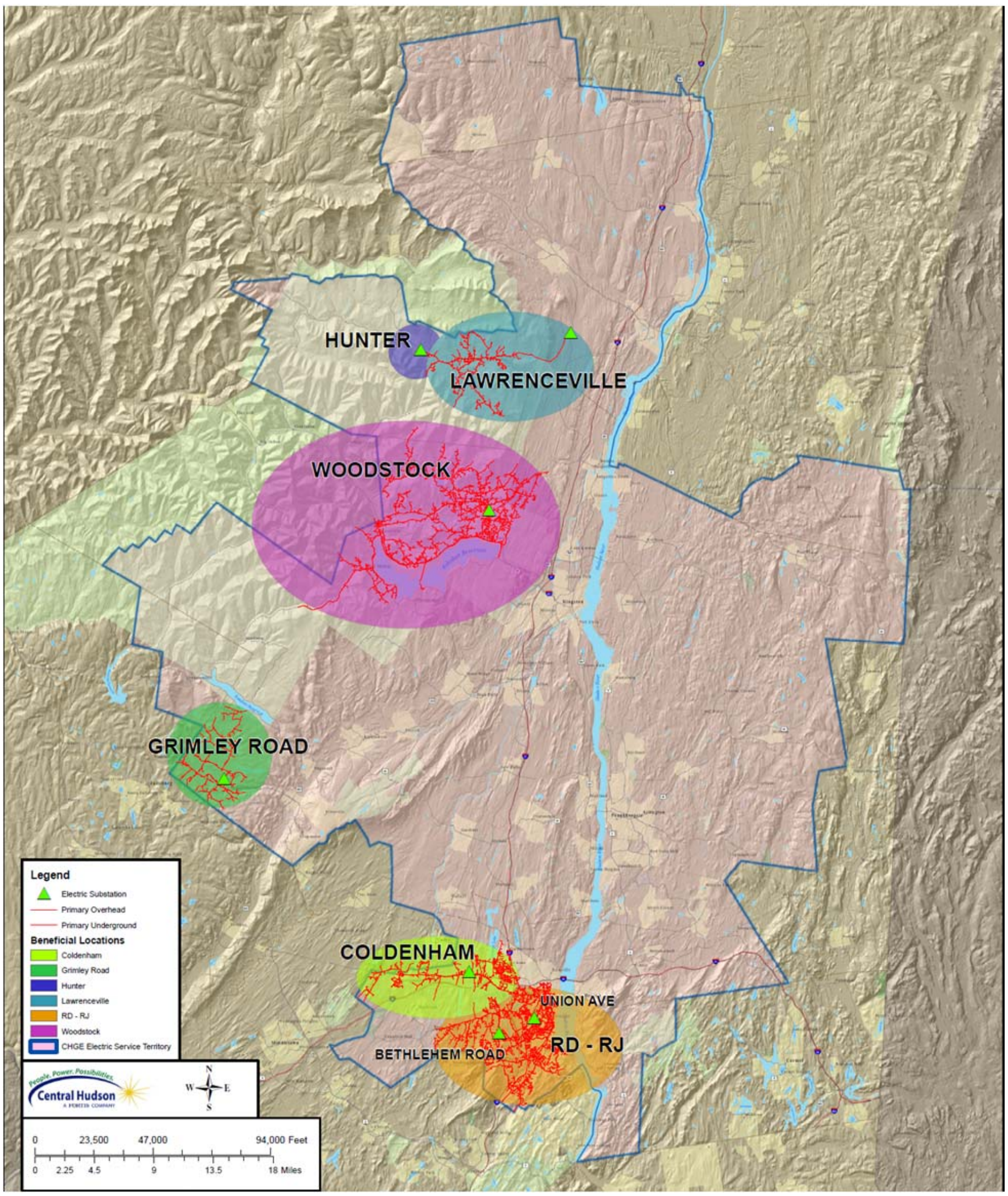
Table 3-10: Poughkeepsie Industrial Load Area – Historical Load Growth Estimates (2010-2015)

Substation	2015 Peak Demand	Design Rating	Growth Factor (2015 =100%)						Annual growth trend (2010-2015)	Std. Error of Forecast
			2010	2011	2012	2013	2014	2015		
Barnegat	8.5	47.8	103.7%	116.2%	120.5%	116.0%	111.2%	100.0%	-1.1%	8.6%
SandDock	23.4	51.0	103.9%	110.4%	106.8%	101.3%	99.5%	100.0%	-1.6%	3.3%
Overall load area	**31.7**	**0.0**	**103.5%**	**112.0%**	**110.8%**	**105.4%**	**102.4%**	**100.0%**	**-1.3%**	**4.3%**

3.3 Beneficial Locations for DERs

Locations were identified as potentially benefitting from DERs when there was a 5% or greater likelihood of triggering an infrastructure investment by 2025 (10 years). In total, this includes one transmission area – the RD-RJ Lines– and four substations – Coldenham, Lawrenceville, Grimley Road, and Woodstock. Two of the substations, Lawrenceville and Woodstock, are winter peaking. While the locations can benefit from DER's, in some instances Central Hudson can provide temporary relief through load transfer or other low cost steps. For areas that lack distribution engineering options for deferring upgrades further, more costs are avoided by placing the right type of DERs with the right availability at those locations.

Figure 3-7: Map of Beneficial Locations for DERs



4 Avoided T&D Cost Estimates

Historically, avoided T&D cost studies have not produced location specific estimates and have not relied on probabilistic methods, which quantify the risk mitigation value of managing demand.

The estimates produced here are based on 2,000 or 10,000 simulations of potential load growth patterns for each substation and transmission area, respectively. For each simulation, we are thus able to assess if the relevant design rating is exceeded, identify the timing of infrastructure upgrade, quantify the magnitude of demand reductions needed to avoid the infrastructure upgrade, and calculate what the avoided costs associated with deferral of infrastructure upgrades would be if demand reductions were in place. The detailed calculations from each of the simulations at each location are used to estimate the expected avoided costs per kW. That is, the probabilistic method assigns T&D avoided costs when, for example, only 10% of potential growth trajectories leads to infrastructure upgrades. This approach quantifies the risk mitigation value provided by resources that reduce demand at the right times at each location.

The purpose of producing avoided T&D costs estimates is not necessarily to establish payments or incentives for DERs. The objective is to allow distributed energy resources to compete against each other and against traditional engineering solutions – wires, transformers, etc. – and thus increase competition and improve efficiency. The avoided cost estimates signal to DER providers not only where DERs are most beneficial but where they are most likely to be monetized. They also provide a reference point and allow comparison of DER costs to traditional engineering solutions.

To deliver value, however, DERs needs to ramp up at the right time and the right place, for the right hours, with the right amount of availability, and the right level of certainty.

4.1 Avoided Transmission Costs

Table 4-1shows the avoided cost estimates for each transmission area and year, as well as the 10-year levelized avoided cost by location. None of the areas are expected to exceed the design ratings over the next few years, but there is a small probability the ratings will be exceeded due to the uncertainty in the growth patterns.

For most transmission areas, the probability of triggering infrastructure upgrades is negligible even at ten years out. As shown in Figure 3-3, the likelihood of triggering an upgrade by 2025 is 6.0% for the RD-RJ lines and 2.6% for the WM Line. Despite the fact that infrastructure upgrades are low probability events, due to the magnitude of the anticipated investments – $5.5M for the RD-RJ lines and $3M for the WM line – demand reductions provide risk mitigation value. The 10 year levelized cost for the RD-RJ lines is 58.05 $/kW-year and $102.11 $/kW-year for the WM line.

The majority of the transmission areas experience little or no avoided costs from DER investments. In practice, all avoided T&D costs are location specific. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low. We include a system wide value, but highlight that it is a weighted average of beneficial locations and locations without any T&D avoided cost value

Table 4-1: Avoided Transmission Cost Estimates ($/kW-Year) – 2016-2030

Forecast Year	Transmission ($/kW-year)										
	Ellenville	Hurley-Milan	Mid-Dutchess	Northwest 115-69 Area	Northwest 69kV Area	Pleasant Valley 69 kV	RD-RJ Lines	Southern Dutchess	WM Line	Westerlo Loop	**Territory wide (Untargeted)**
2016	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2017	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2018	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2019	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
2020	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$231.66	$0.00	**$12.38**
2021	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.58	$0.00	$233.00	$0.00	**$26.65**
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$165.01	$0.00	$233.33	$0.00	**$31.52**
2023	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$139.04	$0.00	$176.03	$0.00	**$36.28**
2024	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$143.78	$0.00	$175.36	$0.00	**$37.42**
2025	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$147.15	$0.00	$177.41	$0.00	**$38.82**
2026	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$144.97	$0.00	$176.77	$0.00	**$38.89**
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$145.94	$0.00	$177.93	$0.00	**$39.47**
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$149.59	$0.00	$185.31	$0.00	**$55.99**
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.50	$0.00	$186.25	$0.00	**$56.19**
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$152.71	$0.00	$187.10	$0.00	**$58.02**
$/kW-Year (10-year levelized)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$58.05	$0.00	$102.11	$0.00	$14.33

Notes: (1) For semi-targeted and untargeted values, the estimates take into account the % of load in the areas with growth related investments; (2) The discount rate, 9.43%, was used to annualize the avoided costs; and (3) All values are nominal $.

4.2 Avoided Distribution Substation Cost Estimates

Table 4-2 shows the 10-year levelized avoided cost estimates by substation and load area. A total of three substations have potential avoided costs – Lawrenceville, Coldeham, and Hunter. Most substations either have ample room for growth or declining loads. For a couple of substations – Grimley and Woodstock – load growth can be addressed via relatively low cost permanent load transfers to neighboring substations. Without targeting, the likelihood that reductions will be at a location where it might help defer or delay substation upgrades is relatively low, diluting the value to $0.23 /kW-year.

Table 4-2: Avoided Substation Cost Estimates ($/kW-Year) – 10 Year Levelized Value

Load Area	Substation	$/kW-Year (10-year levelized)	Load Area	Substation	$/kW-Year (10-year levelized)
1 Northwest	Hunter	$31.46	6 Northeastern Dutchess	EastPark	$0.00
	Lawrenceville	$275.34		Hibernia	$0.00
	New Baltimore	$0.00		Milan	$0.00
	North Catskill	$0.00		Millerton	$0.00
	Vinegar Hill	$0.00		Pulvers Corners 13kV	$0.00
	Westerlo	$0.00		Pulvers Corners 34kV	$0.00
	Load area (untargeted)	$1.04		Rhinebeck	$0.00
2 Kingston - Saugerties	Boulevard	$0.00		Smithfield	$0.00
	East Kingston	$0.00		Staatsburgh	$0.00
	Hurley Ave	$0.00		Stanfordville	$0.00
	Lincoln Park	$0.00		Tinkertown	$0.00
	Saugerties	$0.00		Load area (untargeted)	$0.00
	Woodstock	$0.00	7 Poughkeepsie	InwoodAve	$0.00
	Load area (untargeted)	$0.00		Spackenkill	$0.00
3 Ellenville	Clinton Ave	$0.00		ToddHill	$0.00
	Dashville	$0.00		Load area (untargeted)	$0.00
	Grimley	$0.00	8 Fishkill	Fishkill Plains	$0.00
	HighFalls	$0.00		Forgebrook	$0.00
	Honk Falls	$0.00		Knapps Corners	$0.00
	Load area (untargeted)	$0.00		Merritt Park Industrial	$0.00
4 Modena	Galeville	$0.00		Myers Corners	$0.00
	Highland	$0.00		North Chelsea	$0.00
	Modena	$0.00		Sand Dock	$0.00
	Ohioville	$0.00		Shenandoah	$0.00
	Load area (untargeted)	$0.00		Load area (untargeted)	$0.00
5 Newburgh	Bethlehem	$0.00	9 Poughkeepsie Industrial	Barnegat Industrial	$0.00
	Coldenham	$119.91		Sand Dock Industrial	$0.00
	East Walden	$0.00		Load area (untargeted)	$0.00
	Marlboro	$0.00	10 Fishkill Industrial	Shenandoah Industrial	$0.00
	Maybrook	$0.00		Load area (untargeted)	$0.00
	Union Ave	$0.00			
	West Balmville	$0.00			
	Load area (untargeted)	$0.60			
Territory wide (untargeted)					$0.23

Notes: (1) For semi-targeted and untargeted values, the estimates take into account the % of load in the areas with growth related investments; (2) The discount rate, 9.43%, was used to annualize the avoided costs; and (3) Values are in $2016.

Table 4-3 summarized the expected avoided costs (in nominal $) by year for each substation with potential for avoided costs.

Table 4-3: Substation Locational Specific Avoided Cost by Year ($/kW)

Forecast Year	Coldenham	Hunter	Lawrenceville	System-wide untargeted
2016	$0.00	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00	$0.00
2020	$0.00	$0.00	$414.81	$0.03
2021	$343.87	$0.00	$544.89	$0.19
2022	$292.97	$0.00	$607.05	$0.43
2023	$285.85	$0.00	$610.35	$0.62
2024	$298.68	$445.78	$604.95	$0.85
2025	$313.39	$0.00	$649.32	$0.95
2026	$324.93	$626.94	$628.66	$1.07
2027	$321.31	$655.33	$578.95	$1.14
2028	$316.23	$648.10	$687.88	$1.25
2029	$313.80	$653.86	$616.11	$1.25
2030	$339.49	$698.17	$595.83	$1.45
$/kW-Year (10-year levelized)	**$119.91**	**$31.46**	**$275.34**	**$0.23**

Notes: (1) For system-wide untargeted values, the estimates take into account the likelihood reductions would be in areas with value (2) Values are in nominal dollars.

4.3 Total Avoided System Cost Estimates

Table 4-4 summarizes the system wide avoided T&D costs by year and includes the 10 year net present value used to annualize future value. As noted several times, in practice, all avoided T&D costs are location specific. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. We emphasize that system wide value is essentially a weighted average of a few beneficial locations with numerous locations where reductions do not lead to avoided T&D costs. As beneficial locations are included for non-wire projects, they are removed from the system-wide value.

Table 4-4: System Wide Avoided T&D Cost Estimates for 2016–2026

Forecast Year	Distribution Substation	Transmission	Total
2016	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00
2020	$0.03	$12.38	$12.41
2021	$0.19	$26.65	$26.84
2022	$0.43	$31.52	$31.94
2023	$0.62	$36.28	$36.90
2024	$0.85	$37.42	$38.27
2025	$0.95	$38.82	$39.76
2026	$1.07	$38.89	$39.95
2027	$1.14	$39.47	$40.62
2028	$1.25	$55.99	$57.24
2029	$1.25	$56.19	$57.43
2030	$1.45	$58.02	$59.47
10 Year Levelized Cost ($/kW-year)	$0.23	$14.33	$14.55

Notes: (1) For system-wide untargeted values, the estimates take into account the likelihood reductions would be in areas with value (2) Values are in nominal dollars

5 Key Findings and Conclusions

The key findings from the analysis are:

- Most substations and transmission areas are experiencing declining loads or have ample room for growth over the next 10 years.
- The expected avoided costs vary by location and year and are highly concentrated. Avoided costs are realized if additional resources are placed in the right locations. Without targeting, the value of distributed resources is diluted.
- For many distribution substations and transmission areas that have expected growth, the potential for avoided infrastructure upgrades through DER resources is minimal because there is already sufficient capacity built in the area to meet load growth.
- The avoided cost estimates reflect the uncertainty in the forecasts and the risk mitigation value of demand management. Despite a low likelihood of exceeding design rating in the next 10 years, DER resources can provide risk mitigation value at targeted transmission areas and substations if they are at the right locations, target the right hours, and are available at the right times.
- In practice, all avoided T&D costs are location specific. For system-wide untargeted values, the estimates take into account the likelihood reductions would be in locations with value due to random chance. Without precise targeting, the likelihood that reductions defer or delay transmission upgrades is relatively low.

The study demonstrates the value of developing T&D avoided cost estimates at a local level using probabilistic methods. Because the methodology is relatively novel, it may require future refinements and improvements. Future studies can be further bolstered by conducting sensitivity analyses and refinement of engineering rules, which trigger T&D infrastructure upgrades.

Appendix A   Econometric Models Used to Estimate Historical Growth

The econometric models were purposefully designed to both estimate historical load growth in percentage terms and allow us to weather normalize loads for 1-in-2 weather peaking conditions.
The key to this process was to model the natural log of the daily peak loads as the dependent variable and include year-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, all of the explanatory variables reflect the percent change in load associated with a unit change in the independent variable.

The regressions were estimated on the highest 75 local peak days for each year in the 2010 to 2015 timeframe for a total of up to 450 observations per location. The goal was to include a sufficient number of days that reflected peaking conditions for each year. The number of observations by location varies slightly because of differences in the amount of data available and because peaks occurring on weekends or holidays were excluded. The model estimated daily peaks as a function of weather interacted with day of week, month, and historical year. Weather was included using a process that avoids assumptions about the type of relationship between weather and load. Rather than assume a constant linear relationship, the weather data is split into equally sized bins and a separate relationship is estimated for different temperature ranges—also known as a *spline regression*. All models were estimated using time series methods to take into account auto-correlation.[5]

Figure A-1 illustrates the model output for one location. A separate model was estimated for each substation, transmission area, and planning area. The model explained 98.3% of the variation and, more importantly, produced estimates of the percent change in loads—the *load growth*—relative to 2010, after controlling for weather, day of week, and other factors. Figure A-2 shows the year-to-year growth and the general trend. The growth trend and the amount of year-to-year variation differ by location and are central to developing the probabilistic load forecasts. In addition, the confidence bands for the historical growth estimates are linked to the explanatory power of the models. When explanatory power is high, confidence bands are tight. When explanatory power is lower, confidence bands are broader.

The estimates of year-to-year historical load growth also were used to assess the degree to which growth patterns are related to each other—that is, the degree to which growth in the prior year predicts growth in the following year, technically known as *auto-correlation*. Each individual site had a limited number of individual year growth estimates—five years at most—so the estimate of auto-correlation was developed across all sites. The auto-correlation in growth was 0.75 for substations and 0.52 for transmission areas.

[5] We relied on an iterative feasible GLS model with first order auto-correlation. Other time series options—such as ARIMA and the Newey-West model—do not handle gaps in the time series as easily. All options, however, produce consistent estimates.

Figure A-1: Example Load Growth Econometric Model

Prais-Winsten AR(1) regression -- twostep estimates

Linear regression

Number of obs	=	370
F(30, 336)	=	.
Prob > F	=	.
R-squared	=	0.9832
Root MSE	=	.04923

Dependent variable

Explained variation

lndailypeak	Coef.	Semirobust Std. Err.	t	P>|t|	[95% Conf.	Interval]
year						
2011	-.0314738	.0114131	-2.76	0.006	-.0539239	-.0090236
2012	-.0190394	.0124406	-1.53	0.127	-.0435106	.0054319
2013	-.0041588	.0143032	-0.29	0.771	-.032294	.0239763
2014	-.0592701	.0111966	-5.29	0.000	-.0812943	-.0372459
2015	-.0781381	.0099249	-7.87	0.000	-.0976608	-.0586154
month						
2	-.0087784	.0093905	-0.93	0.351	-.0272501	.0096932
3	-.0043992	.0158393	-0.28	0.781	-.0355558	.0267574
5	-.0935041	.0450242	-2.08	0.039	-.182069	-.0049392
6	-.054681	.0444931	-1.23	0.220	-.1422012	.0328391
7	-.0333242	.0437045	-0.76	0.446	-.1192932	.0526447
8	-.0249745	.0434934	-0.57	0.566	-.1105281	.0605792
9	-.0399489	.0442698	-0.90	0.367	-.1270298	.047132
11	.0667566	.0156461	4.27	0.000	.03598	.0975333
12	-.026894	.0110624	-2.43	0.016	-.0486544	-.0051337
dow						
2	-.0039519	.0096568	-0.41	0.683	-.0229473	.0150436
3	.0030018	.0103159	0.29	0.771	-.01729	.0232937
4	.0004244	.0114791	0.04	0.971	-.0221556	.0230043
5	-.0146542	.0131222	-1.12	0.265	-.0404661	.0111577
cdd60	.0199863	.0017218	11.61	0.000	.0165994	.0233731
dow#c.cdd60						
2	.0016199	.0009015	1.80	0.073	-.0001534	.0033932
3	.0012651	.0009084	1.39	0.165	-.0005217	.0030519
4	.0012951	.0009638	1.34	0.180	-.0006008	.003191
5	.0007154	.0010129	0.71	0.480	-.001277	.0027077
bins_cdd						
1	.1937983	.0323063	6.00	0.000	.1302502	.2573465
2	.1760443	.1233678	1.43	0.155	-.0666261	.4187148
3	-.0030568	.0740123	-0.04	0.967	-.1486427	.142529
4	-.0943377	.0997578	-0.95	0.345	-.2905663	.1018908
5	0	(omitted)				
cdd60	0	(omitted)				
bins_cdd#c.cdd60						
1	0	(omitted)				
2	-.0208899	.0143867	-1.45	0.147	-.0491892	.0074095
3	-.0023679	.0063728	-0.37	0.710	-.0149035	.0101677
4	.0053657	.0070509	0.76	0.447	-.0085038	.0192352
5	0	(omitted)				
bins_hdd						
3	.0404254	.0385893	1.05	0.296	-.0354817	.1163325
4	-.0062006	.0138347	-0.45	0.654	-.0334142	.0210129
5	0	(omitted)				
hdd60	.0040388	.0006694	6.03	0.000	.0027222	.0053555
bins_hdd#c.hdd60						
3	0	(omitted)				
4	0	(omitted)				
5	0	(omitted)				
_cons	2.65174	.0307021	86.37	0.000	2.591348	2.712133
rho	.3315186					

% Change in load relative to 2010

Seasonal effects (independent of weather)

Day of week effects

Weather interaction with day of week

Weather Effects (Spline)

Figure A-2: Example of Historical Load Growth Estimates